Australian Energy Market Commission

UPDATE PAPER

COORDINATION OF GENERATION AND TRANSMISSION INVESTMENT

19 DECEMBER 2019

REVIEW

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 At its meeting in November 2019, the Council of Australian Governments (COAG) Energy Council discussed the AEMC's *Coordination of generation and transmission investment* review, which is considering reforms to deliver new generation and transmission to underpin the future power system. The COAG Energy Council agreed that it will consider the COGATI final report at its March 2020 meeting.[1]

2 In light of this, the final report for this review will be published in March 2020. The final report will include:

- a preferred transmission access model that incorporates stakeholder feedback received through the current review process
- drafting instructions that indicate the scope of rule changes needed to implement the access model
- a preferred implementation timetable for the model.

3 The Commission is continuing to consult extensively with stakeholders in order to better understand their positions and to refine the Commission's preferred access model taking their views into account. In particular, we will be using the time until March 2020 to organise and conduct several targeted workshops with government, market bodies, consumer groups, industry and other stakeholders, including a fifth meeting with our technical working group.

4 We encourage stakeholders to reach out to the project team to schedule a meeting, workshop or teleconference (Tom Walker at tom.walker@aemc.gov.au; or Jess Boddington at jess.boddington@aemc.gov.au).

5 Beyond March 2020, the Commission envisages that there will be considerable additional scope to discuss the merits of, and refine, the access model through the rule change process.

6 In the latest round of consultation, the Commission has heard that most stakeholders agreed that there are issues with the current transmission access framework that need to be addressed.

7 A significant number of stakeholders, including network businesses, consumer groups and a subset of generators and investors, support the proposed access model in principle. Many of these stakeholders suggested ways that the design could be improved or modified in order to increase the benefits of the model and to minimise implementation challenges.

8 The majority of investors and generators were not supportive of the access model. They highlighted both implementation issues and other specific concerns about the model, including that it may decrease liquidity in the contracts market or increase market power.

9 Consistent with stakeholder feedback to-date, key themes for ongoing discussions with stakeholders include:

1 COAG Energy Council, Meeting Communique, 22 November 2019.

- the usefulness of the proposed access model to enable market participants to better manage risks stemming from transmission infrastructure, including the firmness and tenure of the financial transmission rights
- transitional impacts of the reforms, in particular to existing contracts
- quantifying the benefits and costs of reform and modelling potential distributional outcomes.

10 The Commission has heard from the large majority of stakeholders that our previously proposed date of 2022 is too ambitious to implement the access model. In light of the arguments raised, the Commission agrees that a later implementation date would be in the long term interest of consumers.

11 Instead of proposing a new date, we propose a *timeframe* of at least four years from the time that the access model rule changes are made. This is beyond the three years of commonly traded contracts, and allows time for longer term agreements to be renegotiated. This will also allow the implementation date to be coordinated with other reforms under way, including those arising from the Energy Security Board's (ESB's) post-2025 market design project.

12 We also plan to consider a staged approach to reform, whereby the reform may be phased in stages or by region.

13 The Commission intends to use the additional time between now and March 2020 to complete quantitative analysis on the proposed access model. This will include consideration of the impacts, as well as an assessment of the distributional effects in order to inform grandfathering arrangements.

14 The Commission is of the view that change is needed to provide better signals and tools for managing transmission related risks for existing and new generation in response to the transformation that is occurring in the mix and location of generation in the power system. The form of the transmission access reform needs to be determined now to allow an orderly transition and implementation to occur over time. We consider that it is important to develop a detailed model as soon as possible. This is necessary to allow participants to fully understand the proposed approach, and will provide a more concrete basis for them to consider its implications. It will also maximise the time to allow an orderly transition for whatever timeframe is ultimately agreed.

15 The Commission's proposed access model provides a flexible and enduring basis for access into the future. It works hand-in-hand with the Energy Security Board's work on developing changes to the National Electricity Rules to convert the Integrated System Plan (ISP) to action, as well as its post-2025 market design work. The ISP will streamline the regulatory processes required to deliver transmission investment; while access reform will provide both investment and operational signals to generators to better utilise the existing and expanded transmission network.

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1 INTRODUCTION

1.1 Purpose of this paper

At its meeting in November 2019, the Council of Australian Governments (COAG) Energy Council discussed the AEMC's *Coordination of generation and transmission investment* review, which is considering reforms needed to deliver new generation and transmission to underpin our future power system. The COAG Energy Council agreed that it will consider the COGATI final report at its March 2020 meeting.[2] In light of this, the final report for this review will be published in March 2020.

The purpose of this update paper is to provide further information and context to stakeholders ahead of the final report. In particular the paper:

1. **revises the proposed date for implementation of the access model**: After receiving significant feedback from stakeholders that 2022 is too ambitious, the Commission proposes that the access model should be implemented at least four years after the time that the rule changes to deliver the access model are made. This timeframe will allow the implementation date to be better coordinated with other reforms under way, including those arising from the ESB's post-2025 market design project.
2. **sets out how we will consult with stakeholders:** The Commission will continue to consult and engage extensively with stakeholders in order to refine the access model, including organising a series of workshops. The paper also reflects the key themes arising from submissions to date such as: the length and firmness of the proposed financial transmission rights, and managing market power and contract market liquidity considerations. It also sets out how this will inform our engagement.
3. **sets out what quantitative analysis we will undertake:** This will include consideration of the impacts of the reform on the NEM as well as an assessment of the distributional effects, in order to inform grandfathering arrangements.

Any enquiries on this paper should be addressed to either:

- Tom Walker at tom.walker@aemc.gov.au or
- Jess Boddington at jess.boddington@aemc.gov.au

1.2 Purpose of this review

The *Coordination of Generation and Transmission Investment* (COGATI) review is focussed on examining *when* the transmission framework will need to change, and, if so, *what* it will need to change to.

The Commission is of the view that change is needed to provide better signals and tools for managing transmission related risks for existing and new generation in response to the transformation that is occurring in the mix and location of generation in the power system.

However, the Commission considers that it is important to develop a detailed model as soon as possible. This is necessary to allow participants to fully understand the proposed

2 COAG Energy Council, Meeting Communique, 22 November 2019.

approach, and will provide a more concrete basis for them to consider its implications. It will also maximise the time to allow an orderly transition for whatever timeframe is ultimately agreed.

We need to evolve our transmission access framework to support the change in the generation mix joining the national electricity market (NEM). Transmission access reform is vital for the NEM to effectively manage the transition under way in generation technologies, whatever this future may look like.

Access reform complements the ISP to better coordinate generation and transmission investment, resulting in lower total system costs faced by consumers.

This review is undertaken pursuant to a terms of reference received from the Council of Australian Governments (COAG) Energy Council, which asked the Australian Energy Market Commission (AEMC) to implement a biennial reporting regime on these matters.[3]

1.3 Structure of the paper

The paper is structured as follows:

- Chapter 2 provides an overview of the rationale for the proposed access model
- Chapter 3 provides details on key themes arising from submissions to our October discussion papers.
- Chapter 4 provides an update on our modelling approach.
- Chapter 5 discusses the next steps for this review.
- Further detail of the proposed model is provided in appendix A.
- Appendix B discusses similar access models to the one proposed by the Commission that have been implemented elsewhere.
- Appendix C outlines interactions of this project with other ongoing work by the Commission and other organisations.

3 The terms of reference were provided under section 41of the National Electricity Law (NEL) and can be found here: https://www.aemc.gov.au/sites/default/files/content/97164a7bf-49fb-9f2e-f6b996f5a96b/Reporting-on-drivers-of-change-Terms-of-Reference.PDF

2 OVERVIEW OF ACCESS MODEL

2.1 Access reform is needed to better coordinate generation and transmission investment

The electricity sector is undergoing a significant transition. Generation roughly equal to the current size of the NEM (50 GW) is foreshadowed for connection to the grid over the next 10 years, with the NEM replacing most of its current generation stock by 2040.

Unlike the existing power system, the system of the future is likely to be characterised by many relatively small and geographically dispersed generators. This transformation is causing two related issues:

1. Newer generators are unlikely to be located where there is substantial existing transmission to serve them, owing to their different fuel sources compared to the historic generation fleet. Instead, they are being connected in sunny or windy areas, where the network is less strong.
2. New types of generation can be built more quickly than transmission infrastructure required to serve them.

These two trends are creating congestion and loss issues, particularly in North Queensland, South West New South Wales and North West Victoria. Both the Australian Electricity Market Operator (AEMO) and transmission network service providers (TNSPs) are forecasting through their usual planning processes significant increases in congestion across the entire network, driven by the substantial levels of investment in generation.[4]

The ESB's work on developing changes to the national electricity rules to action the Integrated System Plan (ISP) will assist with the problems identified above. The ISP outlines the need for investment in new transmission infrastructure to contribute to reliability and security for consumers.

In particular, it will facilitate transmission infrastructure, by streamlining the regulatory processes for key projects identified in the ISP, while retaining a rigorous cost benefit assessment. This process should shorten the gap between the timing of new generation investment and the transmission infrastructure required to serve it.

However, we also need changes to the access arrangements so that the transition better takes transmission investment needs into account as it progresses. This is because the current framework does not adequately incentivise new generators to make use of existing and new transmission capacity. Instead, it provides incentives to locate and operate in a manner which is inconsistent with minimising total (i.e., generation *and* transmission) system costs. Nor does it provide risk management tools for generators to utilise as part of their investment or operational considerations.

Our reform proposal therefore works hand in hand with the ISP. The ISP will streamline the regulatory processes to deliver efficient levels of transmission investment, while the access

4 Sources include: AEMO, Draft 2020 Integrated System Plan, 12 December 2019, p. 50; TransGrid, *New South Wales Transmission Annual Planning Report*, 2019, p. 7.

reforms provide signals to generators to better utilise the existing and expanded transmission network.

Under our reform proposal, investors will face improved locational signals that more accurately reflect the impact of their investment and operational decision on the total costs of the network. The proposal brings into alignment the financial incentives faced by individual market participants to the physical characteristics of the power system. This will result in generation and transmission being better coordinated, meaning that decisions will be made that best utilise the existing and forthcoming transmission infrastructure. This should lower total system costs for consumers, as well as the industry more generally.

Access reform should improve the efficiency of transmission investment. Firstly, these signals will constitute a new source of information to be incorporated and used as an input into the transmission planning process, including the ISP. Secondly, improved generator and storage locational decisions, which better utilise the network, may refine the transmission planning options pursued.

2.2 The consequences of the current access regime

There are a number of consequences of the current access regime that are exacerbated by the current pattern of generation investment and operational decisions.

The current access regime does not provide appropriate signals to market participants to locate and operate in a manner which is consistent with minimising total system costs. This ultimately results in higher costs for consumers. It also does not appropriately enable market participants to manage risks relating to transmission congestion and losses.

Some parties have argued that more transmission infrastructure is all that is needed in the long term. More infrastructure will alleviate the congestion and adverse loss factors currently being experienced in the market. However, this is likely to lead to uneconomic outcomes in the long term.

If more transmission is built, then congestion will be alleviated in those parts of the network at least initially. This will also create incentives for new generation to connect in these unconstrained areas. Under the current access framework, there are inadequate incentives to stop a subsequent generator connecting beside it and adding congestion, undermining the ability of the first generator to earn revenue from the wholesale market and so impacting its business case.

As more generators connect over time, congestion levels will increase and there will be a return to the issues of significant congestion and dramatically changing loss factors that are being experienced today. The financial uncertainty that generators experience due to the decisions of others will remain under the current framework.

Until the issue of transmission access is resolved, the problems manifesting under the current environment will continue to occur in the future. This evidenced by the fact that issues to do with the access framework and congestion have been considered in at least thirteen reviews including the *Transmission and distribution pricing review* in 1999 by NECA, the *Parer review* in 2002, the *Regulatory and Institutional Framework for Transmission review* by Firecone in

2003, the *Energy Reform Implementation Group (ERIG) review* in 2007, and the AEMC's *Transmission Frameworks Review* in 2013. Problems with the current access arrangements will continue to be significant in the NEM until they are addressed.

Economic efficiency needs to be achieved to deliver the lowest cost outcomes for customers. It is well-established that a power system with no congestion, such that any combination of generators can be dispatched at any given time, is not economically efficient. This is because the costs of the additional investment in transmission would exceed the savings in generation dispatch.

The key is to have the right signals and arrangements to deliver the right balance between transmission investment and generation dispatch. The transmission access framework and the transmission planning process, including the ISP, need to work together to achieve this.

2.3 Proposed access model

Effective price signals - reflecting the marginal value of generating at a specific location in the network - incentivise efficient behaviour, in both investment and operational timescales, lowering total system costs. The Commission's proposed access model seek to provide price signals for generators about where to locate within the transmission network, and when to operate, such that the generation and transmission is better coordinated.

Currently, locational signals to generators do not directly signal the long-term costs of transmission. Current congestion costs are not a meaningful indicator of future congestion costs. Locational signals are important in order to have efficient investment and operational decisions, reflecting the marginal costs that the generator places on the transmission system.

The proposed access model involves two key changes to the current transmission frameworks:

1. Under the proposed model, large-scale generators and storage would receive a spot price that would vary with their location (locational marginal pricing or 'LMP').[5] This pricing would more accurately reflect the cost of supplying electricity from their location on the network, accounting for both transmission congestion and losses. Retailers would continue to pay a regional spot price. Price differences will only arise between locations when there is congestion on the network. When there is not any congestion at a particular time or location, local marginal prices will equal regional prices.[6]
2. Participants would be able to purchase[7] financial transmission rights (FTRs) which pay out on the differences in local prices that arise due to congestion and losses. FTRs would enable market participants to better manage existing transmission congestion and loss related risks, which, in turn, will allow them to have more revenue certainty and the confidence to invest.

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5 The locational marginal price is calculated as the change in the cost of dispatch if one more megawatt (MW) of load is needed to be supplied from that location.

6 Ignoring the effect of losses.

7 On a transitional basis, some FTRs would be allocated to incumbent generators for free.

A more detailed summary of the design elements as set out in the October discussion paper are included in appendix A.

2.4 Benefits of reform

2.4.1 Better locational signals for generation and storage investment

The proposed access model will reveal and place a value on transmission congestion within the system, creating better locational signals for generation and large-scale storage investment. This value will manifest through the difference in local prices in different areas of the network when transmission congestion arises.

For example, consider a wind farm deciding to locate either in the Latrobe Valley or North West Victoria. It may currently consider:

- The resource costs of siting in each area. The wind farm will have high fixed costs, and minimal operating costs. Therefore, the costs of its energy will be heavily influenced by how often it generates and so its capacity factor. In this particular case, the wind farm would note that the Latrobe Valley is not as windy as North West Victoria, and so its capacity factor would be lower and so its cost of energy would be higher in that location.
- The *costs* of land and any environmental permits needed.
- Forecast *information* regarding the availability of transmission capacity, and the relative likelihood of being 'constrained off' or suffering from adverse loss effects. In this case, it would note that a lot of available transmission capacity in the Latrobe Valley is expected shortly; but that North West Victoria is currently heavily constrained. It may also undertake modelling to forecast future revenues, based on forward prices, congestion and marginal loss factors. Its financing, and ability to access debt/equity, will be based on these considerations.

The wind farm is currently not financially incentivised to fully take into account the transmission capacity considerations. This is because it does not face the full cost of congestion being the value of congestion to the market. All generators and large-scale storage within each region get paid the same regional reference price, regardless of where they are located.[8] Therefore, they do not face a strong signal to take these considerations into account.

Our proposed model would send a more direct locational signal to generators and large scale storage providers about transmission capacity ahead of their investment decision. Returning to the same example of the wind farm:

- The abundance of transmission capacity in the Latrobe Valley means that the LMP will often equal the regional reference price, and the price to purchase FTRs will be relatively low.
- The limited transmission capacity in North West Victoria means that the LMP will be lower than the regional reference price when constraints bind, and the price to purchase FTRs will be relatively high.

8 Ignoring losses.

This information better reflects the cost of congestion, and so will be incorporated into the trade-offs that the generator makes about their investment location. It may be expected that the much lower expected value of the FTRs in Latrobe Valley would offset the expectations about North West Victoria being windier. Therefore, the generator may locate in the Latrobe Valley. This will therefore improve the way in which transmission related matters are taken into account in the investment decisions made by generators.

These benefits become greater when storage is considered. Parts of the network that are behind constraints are likely to have relatively low locational marginal prices at the times that the constraints bind, reflecting that the marginal value of generation at these locations and times is low. Access reform will increase the incentives for investors to locate storage in congested parts of the network, because they will be able to "import" and store energy, paying these low prices. When the constraint is alleviated (because, for example, the sun sets or the wind stops blowing), the local price will increase to equal the regional price. Storage can then "export" at this time, and be paid that relatively high price. In this way, storage devices can arbitrage price difference that arise due to the differing value of electricity across the network when congestion occurs.

This will likely have positive follow on consequences for other aspects of the market. Placing storage in congested parts of the transmission grid should increase the amount of energy behind a transmission constraint that can get to market. Namely, it may improve the utilisation of variable renewable energy, reduce (or delay) the requirement for transmission infrastructure upgrades, and ultimately reduce prices for consumers.

BOX 1: WHAT WILL BE THE LIKELY PRICE AND PAYOUT OF FINANCIAL TRANSMISSION RIGHTS?

We have heard from stakeholders that they are interested in understanding what the likely price and payout of FTRs may be. The following example may help with understanding how the price and payout of FTRs are derived.

Consider an FTR that pays out on the difference between the regional price and the local price of a transmission connection point in the network. For simplicity, we will assume that:

- The regional price is always $105/MWh.
- There is a transmission constraint between the local transmission connection point and the rest of the region. This constraint binds one dispatch period in ten.
- When the constraint is binding, the local price is $5/MWh.
- LMPs and FTRs do not include the effect of transmission losses.

Most of the time (i.e. ninety percent of the time), the local price will also be $105/MWh. This is because the local price will only diverge from the regional price when the particular transmission constraint between them is binding.

When the constraint *is* binding, generators that are located at that transmission connection point will receive:

- a local price of $5/MWh
- an additional payment of $100/MWh if they hold an FTR.[a]

The expected *average* payout of the FTR is the price difference between the local price and regional price when congestion binds ($100/MWh), multiplied the probability of congestion (10 per cent). Market participants might be expected to be willing to pay up to this price.

Consequently, the auction price for an FTR might be expected to be up to $10/MW per hour. In return, they get $100/MW per hour when the congestion binds.

Of course, this example is simple. In practice, the regional and local prices will individually vary over time, and the probability of congestion will be likely to be correlated to those prices.

It may also be instructive to look at prices of FTRs in overseas markets, in order to help consider what the price of FTRs may be in the NEM. This is something that we will seek to do ahead of the final report.

Typically the total payout from the product is more than what participants have paid for the product. Reflecting back on this example, this means that the FTR would likely to be less than $10/MW per hour to buy (but would still pay out $100/MW per hour during times of congestion).

Note: a) For the amount of FTR they have purchased.

2.4.2 Better transmission investment

As described above, improved investment decisions by generators and storage should in turn improve the efficiency of transmission investment as facilitated through the actioned ISP rule changes.

Under the proposed model:

- generators would have a stronger incentive to invest in parts of the network that can better accommodate them
- storage devices would be incentivised to locate in weaker parts of the grid in order to profit from price differences, which in turn should alleviate congestion.

These two effects might delay or avoid transmission infrastructure upgrades that would otherwise have been required under the existing regime, reducing total system costs and so reducing consumer prices.

2.4.3 Better risk management

FTRs would enable market participants to better manage existing and future transmission congestion and loss related risks. In turn, this will allow them to have more revenue certainty and the confidence to invest and operate effectively.

Access reform should lower the cost of capital for market participants, ultimately reducing prices for consumers. Generators, in return for purchasing FTRs, will be protected from the implications of another subsequent generator connecting beside it and effectively constraining off that first generator.

If congestion is greater than expected,[9] an incumbent generator would have a risk management tool to protect itself from the effects of this congestion through the purchase of FTRs.

In reaching the conclusion that FTRs will better manage transmission related risk, the Commission notes that there is a difference between:

- the impact of the access model on the risk that generators face (i.e. the *variability* in their net revenue)
- their absolute level of net revenue.

Box 2 below seeks to explain this.

BOX 2: ASSESSING THE RISK AND RETURN OF GENERATORS

Extending the example in box 1 above, assume that a generator has located behind the transmission constraint described in that example. This generator:

- has a capacity of 100MW
- has fuel costs of $5/MWh.

We will assume that when congestion occurs, the generator's output is halved.

Under the status quo arrangements:

- when there is no congestion, the generator generates 100MW. It therefore receives $10,500 per hour (100MW x $105/MWh) and incurs fuel costs of $500 per hour (100MW x $5/MWh), for a spot market margin of $10,000 per hour.
- when there is congestion, it receives the regional price multiplied by its output (50MW x $105/MWh = $5,250 per hour), and incurs fuel costs of $250 per hour (50MW x $5/MWh), for $5,000 per hour spot market margin. Its net revenue from the spot market has halved, as both its output and costs have halved.

Under the proposed access model, assume that the generator buys 100MW of FTRs for a price of $10/MW per hour.

In dispatch intervals where there is no congestion, the generator generates 100MW and so receives $10,500 per hour through the spot market (100MW x $105/MWh), and zero from its FTRs (because there is no price separation). It incurs fuel costs of $500 per hour (100MW x $5/MWh), and FTR costs of $1,000 per hour (100MW x $10/MW per hour), meaning that its overall revenues less its costs for the dispatch interval are $9,000 per hour.

When there is congestion, the generator is constrained down to half its output.[a] It receives $250 per hour through the energy market (50MW x $5/MWh), but a further $10,000 per hour

9 For example, because an additional generator unexpectedly connects to that part of the network.

from its FTR payments (($105/MWh - $5/MWh) x 100MW). It incurs fuel costs of $250 per hour (50MW x $5/MWh) and FTR costs of $1,000 per hour (100MW x $10/MW per hour). Its overall revenue less its costs is again $9,000 per hour and is unaffected by the presence or absence of congestion.[b]

By purchasing FTRs for $10/MW per hour, the generator has received a payout of $100/MW per hour when congestion binds and the local price separates from the regional price. It has protected itself against the risk of congestion, such that the *variability* in the generator's net revenue is less than in the status quo arrangements. That is, the generator's risk has been reduced.

These impacts also affect contracted generators. Assume that the generator holds a 100MW contract. In the current arrangements, when the generator is constrained off, its revenues through the spot market are halved, yet its payments under its contract usually need to be made regardless. Consequently, it may choose to contract for a lower volume to avoid the downside risk of being short when congestion occurs, and making a loss. In contrast, under the proposed model, the generator's revenue is protected via its FTRs, meaning it can more confidently contract for 100MW.

Aligning the financial incentives of individual generators with the physical needs of the system reduces overall system costs, which will ultimately be to the benefit of consumers through lower bills.

Generators' overall net revenue may be different to the status quo as a consequence of introducing the access model, depending on their locational decisions.

Note: a) As discussed in its October discussion paper, the current design of the FTRs is that they are not fully firm in relation to all transmission risks that can arise. This is something that the Commission is interested in modelling, as discussed in Chapter 4.
Note: b) Assuming for simplicity of explanation that there is no change in bidding behaviour as a consequence of the reforms.

2.4.4 Offsetting the cost of transmission charges to consumers

The reform will lower the costs associated with the transmission network for consumers. As discussed above, it will incentivise generators to make better locational and operational decisions, which means the existing and planned transmission infrastructure will be better utilised. Generators will locate such that the network will be used more efficiently; and dispatch outcomes will be more efficient. Over time these benefits will flow through into wholesale electricity prices meaning that consumers will receive benefits.

The money from the sale of FTRs in an auction will directly offset consumer bills. This means that, not only will consumers receive the indirect benefits as a result of more efficient locational and operational decisions (discussed below), they will also receive the direct benefit of reduced transmission charges.

2.4.5 Better operational signals for more efficient dispatch

The proposed access model more accurately signals the value of supplying electricity at each location. This should improve the efficiency of dispatch by removing existing incentives on generators or storage devices to operate their assets in a manner which is inconsistent with minimising total system costs.

For example, the current arrangements can give rise to race to the floor bidding. Race to the floor bidding results when generators or storage devices know that the offers they make will, in all likelihood, not affect the settlement price they receive as a result of congestion between them and the rest of the market. When the system is congested, generators and storage know that the regional reference price is likely to be higher than usual, and that they are not going to receive access to it unless they are dispatched.

Race to the floor bidding can involve a generator or storage device behind a constraint bidding at the market floor price (-$1,000/MWh) to maximise its dispatch quantity. This can result in inefficient dispatch through higher cost generation resources being dispatched instead of lower cost resources.

The introduction of local prices should eliminate race to the floor bidding of this nature because generators that bid at the floor price risk setting the local price at that bid price. Instead, they will have an incentive to bid more reflective of their underlying costs. This will benefit consumers in the long-run.

Again, these benefits become more material when considering storage. Under our proposal, storage behind a constraint will be incentivised to charge when there is congestion. For example, if there is congestion then storage will face a low local price, and so import from variable renewable generation that would otherwise go to waste. When the congestion is alleviated (for example, when it becomes less windy or the sun sets), the local price will increase to the regional price,[10] and so the storage device will be rewarded for exporting the renewable energy it stored during the congestion event. This allows more renewable energy to ultimately get to market, and offset transmission investment that might otherwise have been undertaken to alleviate the congestion.

In contrast, under the current arrangements where all generation receives the same price, if there is congestion, the regional price may be high and storage behind the constraint would be incentivised to export, making the congestion worse. This occurs since all generators and large-scale storage in a region face the same regional reference price. This can result in renewables getting spilt (or constrained off).[11]

BOX 3: OUR REFORM PROPOSAL SUPPORTS DE-CARBONISATION OF THE GRID

Under our reform proposal, market participants that have the biggest impact on reducing system costs will receive higher prices, while market participants which exacerbate constraints receive lower prices. This means that no particular generation technology is inherently favoured or penalised.

10 Ignoring the effect of losses on prices for simplicity of explanation.

11 An example of how the proposed model can improve dispatch efficiency is provided in Appendix B of the Commission's July COGATI discussion paper: https://www.aemc.gov.au/sites/default/files/2019-06/COGATI%20-%20directions%20paper%20-%20for%20publication_0.PDF

All generation technologies, including low emission technologies, will be provided stronger incentives to locate where there are less transmission constraints. As a result, they will be able to dispatch a higher proportion of their output, offsetting higher emission resources. Currently, low emission technologies are incentivised to locate where there are good wind or solar resources but the transmission infrastructure is insufficient to accommodate them. This means that, despite the good resources, a proportion of their generation may be wasted and other generation is alternatively dispatched.

The access regime is also particularly well-suited to promote efficient investment and operation of storage devices such as batteries, in contrast to the existing arrangements.[a]

Under our proposed reform, the owners of storage devices, as well as the system as a whole (including consumers) will benefit. This is because storage devices will be better incentivised to invest in congested parts of the network to alleviate constraints. They will enjoy relatively low prices at times of congestion, meaning that they will store energy using renewable generation behind the constraint that would otherwise have gone to waste. When the constraint is alleviated (perhaps because the sun sets or the wind stops blowing), the local price rises to equal the regional price, and the storage device is paid this higher price to export the electricity it has stored. This increases the amount of renewable generation used, reduces costs, and may also offset transmission investment.

In contrast, under the current arrangements, storage devices are not provided the appropriate price signals to invest in congested parts of the network because they receive and pay the regional price regardless of the congestion. If, despite these incentives, a storage device *were* to be located behind a constraint, it may seek to export if the regional price is high (in order to be paid that price), exacerbating rather than alleviating the congestion. Even less renewable generation would be used as a consequence, and unnecessary transmission investment may be prompted and paid for by consumers.

Note: a) An example of how the proposed model improves investment incentives for storage to locate in efficient locations is provided in Katzen and Leslie, *Revisiting Optimal Pricing in Electrical Networks over Space and Time: Mispricing in Australia's Zonal Market*, December 2019, pp.49-53. The example illustrates the investment incentives for storage and wind under local marginal pricing and the existing regional pricing regime.

2.4.6 Better treatment of losses

Intra-regional transmission losses are currently reflected in dispatch through the use of static marginal loss factors that are set annually by AEMO. These are calculated as the volume-weighted average of forecast marginal loss factors for a connection point over the year, based on simulated network flows.

The Commission is currently considering a rule change regarding the use of marginal loss factors in the National Electricity Market. In its draft determination, the Commission determined that marginal loss factors are preferred compared to average loss factors or other variations to how loss factors could be determined.[12]

12 AEMC, Transmission loss factors, Draft rule determination, 14 November 2019.

The Commission has proposed the introduction of dynamic loss factors in the proposed access model. If dynamic marginal losses are implemented, losses will be explicitly modelled on each branch of the transmission system and incorporated into local prices. This will help the lowest cost combination of generation to be dispatched at any given time, improving the efficiency of dispatch. As outlined in chapter 4, the Commission is continuing to investigate the potential magnitude of dispatch efficiency gains from introducing more dynamic marginal losses.

3 STAKEHOLDER FEEDBACK AND INITIAL RESPONSES

The consultation process for the COGATI review has thus far included:

- publishing five papers for discussion this year, including a consultation paper, a supplementary information paper, a directions paper, a discussion paper on access reform and a discussion paper on renewable energy zones
- forming a technical working group from industry, market bodies and consumer groups to consult on the proposed reforms, which has met four times
- holding two public workshops and a variety of smaller targeted workshops with industry and government stakeholders
- meeting with a diverse range of stakeholders and industry groups, including across the sector: generators (different sizes, portfolios, technology types); networks; consumer groups (large and small); investors; governments; and market bodies.

The most recent round of public consultation has been centred around the proposals contained in our October discussion papers. To date, 63 stakeholders have made submissions on these discussion papers. Submissions can be found on the COGATI project web page.[13]

Submissions on the discussion papers came from a wide variety of stakeholders, including generators, network businesses, renewable energy companies, equity investors, market and industry bodies, governments, and energy users and consumer groups.

Key themes from stakeholder submissions included:

- Almost all stakeholders noted that the proposed July 2022 implementation date for the proposed access reforms is too ambitious.
- Most stakeholders agreed that there are issues with the current transmission access framework that need to be addressed, notably the incentives for market participants to invest and operate in a manner consistent with minimising total system costs, and the ability of market participants to manage transmission related risks.
- A significant number of stakeholders, including network businesses, consumer groups and a subset of generators and investors, support the proposed access reforms in principle. Many of these also suggested ways that the design could be improved or modified in order to maximise the benefits of reform and minimise implementation challenges.
- The majority of investors and generators were not supportive of the access model. They highlighted both implementation challenges issues as well as and other specific concerns about the model, including that it may decrease liquidity in the contracts market or increase market power.
- Some stakeholders highlighted the importance of financial transmission rights to be fully firm to hedge market participants.

13 See: https://www.aemc.gov.au/news-centre/media-releases/summary-submissions-transmission-access-reform-model

- Many stakeholders suggested the need for clear implementation and grandfathering plans for this reform.
- Most stakeholders supported the development of detailed cost-benefit analysis and modelling on the financial impact on market participants if the proposed access reform was introduced.

3.1 Implementation date

3.1.1 Summary of submissions

Most stakeholders expressed their concern with the proposed implementation date of July 2022. This is because:

- forward contracting is already occurring for 2022 on the basis of the current framework
- there are other significant reforms locked in that require resourcing and have an implementation date near 2022
- a closer implementation date increases regulatory uncertainty, which has the potential to slow investment in the immediate term
- it is ahead of the substantial market redesign currently being considered by the ESB through the post-2025 market design review.

3.1.2 Next steps in relation to feedback

In light of the feedback provided by stakeholders, the Commission considers that the proposed date of implementation of 2022 is too soon to implement the access model.

We have heard from stakeholders that contracts, including Australian stock exchange (ASX), over the counter (OTC) and off take agreements are already being traded for 2022. Therefore, an implementation date of 2022 could create considerable cost, risk and disruption in 'opening up' these contracts, as well as imposing investment risk on the NEM which would clearly not be in the long-term interests of consumers. A closer implementation date has the potential to slow investment and increase risk in the immediate term.

In addition, we are conscious that there are a lot of reforms being considered in the market at the moment that need to be sequenced in a coordinated way. Therefore, instead of proposing a fixed date, we are instead planning to propose a timeframe for when the reforms should come into effect after the rules have been made. This would allow the implementation date to take into account complementary reforms, such as the proposals under the ESB's 2025 market design, five minute settlement and wholesale demand response.

We propose an implementation date of at least **four years** from the time that the rules to implement the model are made. This is beyond the three years of commonly traded contracts, meaning that these contracts could continue to be traded without disruption to the point that the final decision to implement the access model is made. In addition, it is well into the life of longer term off take agreements (including power purchase agreements), allowing time for the implications to be considered and for renegotiations if necessary.

The Commission acknowledges that some contracts are longer than four years and that there will still be a degree of disruption and cost to the market as a consequence. The Commission is continuing to assess the materiality of these concerns. One potential way to mitigate these issues is through the proposed grandfathering arrangements. We will continue to consider and consult upon these issues as part of the rule change processes next year.

We also plan to consider a staged approach to reform, whereby the reform may be phased in stages or by region.

Further, the Commission considers that it is crucial to continue to develop the access model itself as quickly as practicable, to provide the market with a clear and timely understanding of the changes. This will minimise regulatory risk and disruption while the reforms are being developed. To this end, in 2020, the Commission intends to progress the rule changes to implement the reforms.

3.2 Feedback on need for reform

3.2.1 Stakeholder views

Most stakeholders in their submissions agreed there were issues with the current framework that need to be addressed. While a significant number of stakeholders supported the proposed reforms in principle, many highlighted practical implementation challenges or that it is currently an inappropriate time to undertake such big and complex reform.

Consumer groups were generally supportive of the proposed reforms. Consumer groups considered it is unfair that consumers will pay the full cost for network augmentation and new generator access that is required over the coming years. These stakeholder groups considered that the proposed changes will ensure that the costs and risk of new energy infrastructure are met by those who will benefit the most from it and are in the best position to manage the costs and risks.

In contrast, many generators and investors were concerned with potential increased complexity and volatility in the market; however, the reasons for this differed across the stakeholder group. For example, some parties were concerned about the impact that the COGATI review is currently having on prospective investment in the market; while others were more concerned about this on an enduring basis. Others considered that actioning of the ISP will solve many of the issues the COGATI review is seeking to solve.

A number of stakeholders did not believe sufficient evidence has been produced to justify a material change to the regulatory framework; in particular, they were of the view that the costs of the reform are likely to outweigh the benefits.

Networks agreed with the Commission’s view that there is a need for reform. Networks broadly supported the proposals and considered they will be a useful complement to the ISP. Network businesses considered that the proposal has the potential to result in a benefit to consumers from more efficient market outcomes and provides new tools for generators to manage risks, which has been cited as a substantive barrier to new generation investment.

3.2.2 Next steps in relation to feedback

The Commission will continue to consult over the upcoming months in order to understand stakeholder concerns in more detail. In particular, this will allow us to better understand the myriad of reasons and concerns being noted by the generation and investor community on the need for, and materiality of, reform.

In particular, in order to better inform this, the Commission will be seeking to undertake modelling as discussed in chapter 4. This will help address the concern that the need for reform has not been sufficiently articulated.

3.3 Feedback on the access model

3.3.1 Stakeholder views

Locational marginal pricing

Stakeholders had mixed views on locational marginal pricing. Most consumer groups and network businesses, as well as the Australian Energy Regulator (AER) and Australian Competition and Consumer Commission (ACCC), supported locational marginal pricing because it will provide better price signals, which can improve both investment and operational decisions. Several of these stakeholders highlighted that there are design issues to work through within locational marginal pricing, including how to best mitigate market power concerns.

The majority of generators and some investors opposed wholesale pricing reform. These stakeholders consider that the proposal is complex and disproportionate to the identified problems. These parties also suggested that the reform will have substantial implications for existing contracts and market liquidity, while investment signals will not be materially improved. Some parties acknowledged that these concerns may be more on a transitional basis, rather than enduring.

Financial risk management

Stakeholders had mixed views on the introduction of financial transmission rights. Most consumer groups and network businesses, as well as the AER and ACCC, supported the proposal as it can improve the ability of market participants to manage the risks of congestion and losses by purchasing financial transmission rights.

Generators and investors noted the need for FTRs if dynamic regional pricing is implemented. However, they had concerns with the proposal, suggesting that FTRs as currently designed would not provide an effective risk management tool as their tenure is too short. Stakeholders also wanted more clarity on how firm these rights may be.

3.3.2 Next steps in relation to feedback

We will consult over the upcoming months and work with stakeholders on the particular issues that cause concern about the proposed access model.

Particular focus areas in relation to dynamic regional pricing include calculation and scope of the regional price, how losses are formulated, and whether there are any market power concerns.

The key areas we intend to explore in relation to financial transmission rights include their firmness, tenure and lead time, the treatment of losses and transitional considerations.

The key topics we intend to explore in relation to financial transmission rights include:

- **Firmness.** Many generators expressed concern that financial transmission rights will not improve their ability to manage congestion risk relative to the status quo, because these rights will not be fully firm. In 2020, the Commission plans to conduct a simultaneous feasibility study to provide further insights into the likely firmness of the FTR products under the proposed funding arrangements.[14] In the interim, we are keen to further understand stakeholder views on the effectiveness of FTRs, as compared to existing strategies to manage congestion risk.
- **Tenure and lead time.** The concept design proposed that quarterly financial transmission rights would be available for purchase three to four years in advance. Most generators considered that this tenure and lead time would not be long enough to support investment in new projects. Suggestions included that tenure and lead time should be aligned to asset lives or the duration of debt financing. The Commission notes that markets elsewhere have longer FTR products than three to four years. For example, the Californian market has a ten-year FTR product. The Commission considers it is worthwhile to consider an increase in the tenure of the FTR product, since, as suggested by both generators and investors, this would increase the financial certainty for generators.
- **Hedging losses.** Many stakeholders expressed interest in the concept of financial transmission rights that would allow market participants to hedge the price impact of changes in marginal losses. However, most submissions requested further information on the specific design details of these products. The Commission is continuing to progress a concept design for financial transmission rights that hedge losses, for inclusion within the final report.

14 In the discussion paper, we proposed that financial transmission rights would be funded by available settlement residues. If settlement residues are inadequate, financial transmission right payouts would be scaled back accordingly. If there are excess settlement residues in any period, these would be directed to a fund that would be used to offset the need for scaling in other periods.

4 MODELLING

4.1 Approach to modelling

The discussion paper set out a plan for modelling to inform the costs, benefits and policy design of the reform.

First, we think it is important to look at the implementation of comparable reforms in overseas markets, in relation to both the costs and benefits of the reforms. This will look at the impacts on the cost of generation from changes to the cost of capital, the prevalence and effects of race to the floor bidding, historic measures of the cost of congestion and the implications for market power of a move to local marginal pricing. Some initial findings are set out below, but more fulsome discussion will be contained in the final report.

Second, we also think it is important to have quantitative impact analysis undertaken by March 2020, to provide more information on the impacts of introducing the access model to the NEM. This will include looking at aspects such as:

- wholesale market dispatch
- generation and transmission investment
- changes to cost of capital

The Commission also intends to analyse distributional impacts of the reforms by March 2020, with a view to informing the design of specific policy elements of the reforms, in particular, the terms under which FTRs may be grandfathered.

Further information will be provided on both the appointment of consultants to conduct the work and on the details of the methodology to be used.

4.2 International examples of nodal markets

Initial consideration of international cases of the implementation of LMPs and FTRs provides a number of insights that will help to inform more detailed modelling of access reforms as applied to the NEM.

A number of markets internationally have implemented LMPs and FTRs. This has often been in response to the same fundamental changes and investment patterns seen in recent years in the NEM, in particular, significant investment in renewable energy generation in different parts of the transmission network.

All US markets have implemented some form of locational marginal pricing with FTR type instruments. These changes were introduced between 1998 and 2010. New Zealand has had a locational marginal pricing market for some years and in 2013 implemented FTRs. Singapore has operated a locational marginal pricing market since 2003.

Detailed cost benefit studies of access reform in different jurisdictions are not always available, and post implementation assessments of the costs and benefits are scarce. However, where these have been completed, they have demonstrated the significant benefits to the efficiency of dispatch and management of congestion in current time periods and the potential for more efficient siting of generation and transmission investment over the longer term.

Figures for some US markets show significant benefits versus the costs of implementing the reforms.[15] Benefits tend to be reported in the hundreds of millions of US dollars but vary considerably.

The ERCOT market conducted two studies, one in 2004 prior to reform and one in 2008 when some implementation costs had already been incurred.[16]The later study reported NPV benefits of $520m over ten years of market operation, associated with lower production costs of electricity in current periods and in future periods augmented by the more optimal siting of new generation. However, the study also reported an increase in implementation costs from a range of $108-157m (in 2004 dollars) to over $600m in 2008 dollars. This increase in cost was in part attributed to a delay in implementation. Consumer benefits were estimated to have an NPV of $5.6bn (a large part of which is represented by consumers receiving additional FTR auction revenue) and no NPV for production cost savings was calculated beyond the first ten years of operation. Post implementation reports by the ERCOT's Independent Market Monitor noted the benefits of the reforms.[17]

Other US markets show significant benefits as reported in the Climate Policy Initiative summary, although with less detail on the costs of implementation.

In the California market, a study completed in 2011 (Wolak) concluded that the nodal market resulted in savings of 2.5% per annum in the total fuel costs consumed for the level of electricity output, equivalent to $105m per annum.[18]

The New Zealand cost benefit assessment completed for FTR implementation showed a significant net benefit, and this has been borne out in the generally regarded success of the operation of FTRs in the New Zealand market and the expansion of the scheme over time.[19]

The Commission is mindful that caution needs to be taken in interpreting these results. For example, in some instances, LMPs and/or FTRs have also been introduced alongside other reforms and it is not possible to identify the specific benefits of introducing LMPs and FTRs on their own. This illustrates the importance of additional in-depth work focusing on the specific circumstances of the NEM and the likely net benefit of the access reform proposals.

15 Neuhoff and Boyd, *Climate Policy Initiative study of international experience of nodal pricing implementation*, 2011, Climate Policy Initiative, https://climatepolicyinitiative.org/wp-content/uploads/2011/12/Nodal-Pricing-Implementation-QA-Paper.pdf. This study is also referred to by the International Renewable Energy Agency, *Increasing Space Granularity in Electricity Markets, Innovation Landscape Brief*, 2019, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Increasing_space_granularity_2019.pdf?la=en&hash=AFFB9C326FDEE85C43B1B6E66F6554F4AF77E23F

16 2008 study: http://www.puc.texas.gov/industry/electric/reports/31600/puct_cba_report_final.pdf

17 See, for example, Public Utility Commission of Texas, *state of the market report for the ERCOT wholesale electricity market*, 2010 and 2011, found at http://interchange.puc.texas.gov/Search/Filings?UtilityType=A&ControlNumber=34677&ItemMatch=Equal&DocumentType=ALL&SortOrder=Ascending

18 Wolak, 'Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets', 2011

19 New Zealand Electricity Commission, Consultation Paper, Managing location price risk proposal, 13 September 2010.

5 NEXT STEPS FOR THE REVIEW

The Commission will conclude this review by March 2020, by providing a final report to the COAG Energy Council. Pending the outcomes of the cost-benefit analysis, the final report will include:

- an access model that incorporates stakeholder feedback and the outcomes of the cost benefit analysis
- drafting instructions that indicate the scope of rule changes needed to implement the access model (noting that the design of the model will be further consulted upon and refined through the rule change process in 2020)
- a preferred implementation timetable for the reform.

The access model in the final report will be a 'working' model. This will allow us to receive feedback, and discuss and refine it with stakeholders during the rule change processes next year.

The COAG Energy Council also discussed progress on renewable energy zones at its November meeting and asked the ESB to expedite work on short-term actions to progress renewable energy zone connections. We are working closely with the ESB, AEMO, and AER on this and our final report will also make recommendations with regard to renewable energy zones.

Between now and March, the Commission will:

- refine the access model outlined in the October discussion paper
- develop its recommendations with regard to renewable energy zones (also see appendix C)
- continue to consult widely with stakeholders, with a particular focus on the investment community to better understand their concerns regarding the implementation and ongoing risks of the access model
- organise and schedule several targeted workshops with governments, market bodies, consumer groups, industry and other stakeholders
- hold a fifth technical working group meeting
- carry out modelling of the costs and benefits of the reform, as well as an assessment of the distributional effects, in order to inform grandfathering arrangements.

While the final report will conclude this stage of the review, the Commission notes that there will be considerable opportunity for stakeholders to continue to provide feedback on, and refine, the access model throughout 2020 during the rule change process.

ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
CEFC	Clean Energy Finance Corporation
COAG Energy Council	Council of Australian Governments Energy Council
COGATI	Coordination of Generation and Transmission Investment
Commission	See AEMC
ESB	Energy Security Board
FERC	United States Federal Energy Regulatory Commission
FTR	Financial Transmission Right
LMP	Locational Marginal Price
NEL	National Electricity Law
NEO	National electricity objective

A SUMMARY OF KEY DESIGN FEATURES

The following three tables provide the specification of locational marginal pricing, financial transmission rights, and the procurement of financial transmission rights as set out in the October discussion paper. As noted above, the Commission is considering changes to this design in light of feedback and further analysis. Key topics for further consideration include:

- the calculation of the regional price
- tenure and lead time for FTRs
- dynamic loss factors and FTRs which account for losses
- the firmness of FTRs.

Table A.1: Summary of key design features for locational marginal pricing

ISSUE	PROPOSED DESIGN CHOICE
What participants will face the locational marginal price?	Scheduled and semi-scheduled wholesale market participants (including scheduled loads) would be settled at the locational marginal price at their transmission connection point. Non-scheduled market participants (including retail load) continue to face a common regional price for the region they are located in. Some participants would have the option of becoming scheduled should they wish to face their locational marginal price. Market participants would, however, not otherwise be able to opt in or out of facing a locational marginal price. Where the option of selecting their participation category is available to a market participant and exercised by that market participant, it would have to wait 12 months before it could reverse that decision.
What network constraints will influence locational marginal prices?	Under the proposed approach to dynamic regional pricing, locational marginal prices would differ across the network when certain thermal and non-thermal transmission constraints arise. These constraints must relate to the shared network and be included in the NEM dispatch engine (NEMDE).
How is the regional reference price calculated?	Ideally, the regional price would be the volume weighted average price (VWAP) for unscheduled demand and supply within the region.
Are loss factors included in wholesale electricity prices?	Locational marginal prices as well as the regional price will include dynamic loss factors.
How are issues of market power dealt	The Commission does not envisage that market power will be increased as a result of these reforms. As discussed in Chapter 7 of

ISSUE	PROPOSED DESIGN CHOICE
with?	the October discussion paper, we will undertake specific impact analysis to determine the significance of market power considerations under dynamic regional pricing. If we do need a market power mitigation mechanism, then an ex ante offer cap would be introduced in the event that a generator was deemed to be pivotal (i.e. deemed to have market power at that specific time and location). The offer cap would be set at a value related to the conditions in the wholesale market at the time the cap is applied. In addition, the AER should review its existing wholesale market monitoring functions and processes, with the potential to introduce more stringent provisions in the event of a material problem.

Table A.2: **Summary of key design features for the financial transmission rights**

ISSUE	PROPOSED DESIGN CHOICE
What type of financial transmission rights are offered?	The type of financial transmission rights that would be offered would be option instruments, which only ever result in a positive payment. This means that the financial transmission right would never result in a payment liability for the right holder.
What prices do the financial transmission rights refer to?	Market participants would be able to buy financial transmission rights that pay out on the price difference between: • a local price and any regional price • a regional price and any other regional price.
When do the transmission rights pay out?	Market participants would be able to acquire rights which pay out: • at all times of the day ('continuous rights'), or • at specific pre-defined times of the day ('time of use' rights).
Where does the revenue to back the transmission rights come from?	The source of revenue to back financial transmission rights would arise from the difference between what generators are being paid and load is paying under dynamic regional pricing. Excess settlement residues in a given time period would accumulate in a fund administered by AEMO. This would be drawn down from when there is insufficient settlement residue in a different time period.

ISSUE	PROPOSED DESIGN CHOICE
	When the fund is exhausted, FTR payouts would be scaled to the extent necessary.
How are losses hedged?	Financial transmission rights should hedge the risk of price differences arising from losses. Specific details of these instruments is yet to be determined.

Table A.3: **Summary of key design features for the procurement of financial transmission rights**

ISSUE	PROPOSED DESIGN CHOICE
Method of sale for financial transmission rights	Financial transmission rights would be sold through a series of simultaneous feasibility auctions of the network run by AEMO, with input from TNSPs being used to set the parameters of how many financial transmission rights could be sold. The auction would determine the quantity and combination of financial transmission rights sold, given market participants willingness to pay for them and the expected physical characteristics of the network. The simultaneous feasibility auction is designed to provide financial transmission rights with an appropriate level of firmness.
Tenure of financial transmission rights and lead time	Quarterly products would be available up to three to four years in advance. As noted in chapter 4, following stakeholder feedback we are considering a longer tenure.
Participants in the auction	Only physical market participants should be able to purchase financial transmission rights in the auction run by AEMO with the payout on the difference between local prices and regional prices. In addition, their ability to purchase these financial transmission rights through the auction run by AEMO should be capped at some measure of their physical capacity in the market. In contrast, all market participants (including non-physical participants) would only be able to purchase financial transmission rights that payout on the difference between two regional prices. Anybody would be able to participate in any secondary market for FTRs which emerges.
Transparency of procurement process	AEMO should maintain a register of the amount of financial transmission rights sold at auction and the clearing price. The register would also include information about the current holders of financial transmission rights, including where changes in ownership occur due to secondary trades.

B SIMILAR ACCESS MODELS ELSEWHERE

LMP and FTRs have been implemented in electricity markets elsewhere, including those with a considerable variety of other market design features. The proposed design is likely to be flexible to a range of different possible NEM market designs that may be implemented in the future.

The underlying rationale for the implementation of LMPs and FTRs in other markets are the same as those outlined above: a desire to provide appropriate, location specific price signals for market participants, and the tools to allow them to manage transmission risks. However, the proposed model reflects the unique features of the NEM, including the fact that it is a relatively, long, stringy power system, as well as the fact that the wholesale spot market sits alongside the contract market.

Locational marginal pricing and financial transmission rights are well-established in both theory[20] and practice. Bohn, Caramanis and Schweppe introduced the concept of locational marginal pricing in 1984.[21]

New Zealand's market design has featured locational marginal pricing since its start in 1996. Locational marginal prices are an aspect of the US Federal Energy Regulatory Commission (FERC's) standard market design template, having been progressively adopted in all US organised electricity markets starting with PJM in 1998. In 2002, FERC noted that:[22]

> LMP – should encourage short-term efficiency in the provision of wholesale energy and long-term efficiency by locating generation, demand response and/or transmission at the proper locations and times.

The International Energy Agency has stated that:[23]

> Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers.

Furthermore, the same or similar access models have been repeatedly contemplated in the past for the NEM. For example, the Parer review in 2002 noted that:[24]

> The long run solution to the various transmission inadequacies, particularly the issue of providing clear locational signals for investment, lies with full nodal pricing [ie,

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20 For example, see: Katzen and Leslie, *Revisiting Optimal Pricing in Electrical Networks over Space and Time: Mispricing in Australia's Zonal Market*, 2019; Hogan, W.W., *Transmission congestion: the nodal-zonal debate revisited*, Harvard University, John F. Kennedy School of Government, Center for Business and Government, 29(4) 1999; Cramton, P., *Electricity market design*, Oxford Review of Economic Policy, 33(4), pp. 589-612; Wolak, F.A., The Role of Efficient Pricing in Enabling A Low-Carbon Electricity Sector, 2019.

21 Bohn, R.E., Caramanis, M.C. and Schweppe, F.C., *Optimal pricing in electrical networks over space and time*, The Rand Journal of Economics, pp. 360-376, 1984.

22 : Federal Energy Regulatory Commission, *Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design*, March 2002, p. 6.

23 International Energy Agency, *Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience*, p. 16, 2007.

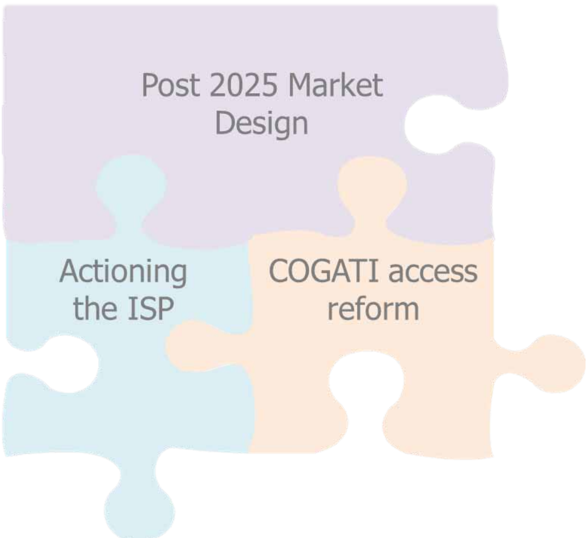
24 Parer et al., *Towards a truly national and efficient energy market*, p. 28, 2002

locational marginal pricing for all market participants, including load].

C INTERACTION WITH OTHER ONGOING WORK

There are a number of projects currently under way looking at reforming the transmission framework, which the Commission is actively involved in. These projects are illustrated in figure 2.1 below.

Figure C.1: Integration of market reforms



Source: AEMC

C.1 Transparency improvements

The Commission is, and has recently considered, two rule changes that aim to improve transparency of the transmission frameworks:

- On 24 October 2019, the Commission published a final determination that, amongst other things, means that market participants are better informed of proposed connections which may assist them with their operational and investment decision-making.[25]
- On 14 November 2019, the Commission published a more preferable draft rule that preserved the existing marginal loss factor framework, but would include refinements to the NER that would provide AEMO more flexibility in its methodology for calculating marginal loss factors.[26]

These can be considered to be increasing transparency and locational signals in the current environment, consistent with the principles of the proposed access model.

25 AEMC, *Transparency of New Projects, Rule determination*, 24 October 2019

26 AEMC, *Transmission loss factors, Draft rule determination,* 14 November 2019

C.2 Streamlined transmission planning and regulatory decision-making

The proposed access model will work hand-in-hand with improvements to the transmission planning and investment decision-making frameworks under the ISP rules. These are currently being developed by the Energy Security Board (ESB). Draft rules were published for consultation by the ESB on 20 November 2019.[27]

As noted above, the actioned ISP will promote transmission planning and investment decision-making in a streamlined way, while maintaining a cost-benefit assessment for consumers. The network planned under the ISP and transmission planning processes will inform the level of network investment that occurs, and in turn the network capacity that is auctioned off for FTRs.

The access model will work hand in hand with the actioned ISP planning and investment processes and send the appropriate price signals to market participants to utilise the transmission network effectively - both in investment and operational timescales - and for market participants to better manage transmission related risk.

C.3 2025 market design

The Commission is also working closely with the ESB on its post-2025 market design project. It has sought to design an access model that, while adapting the NEM to meet the trends arising from the transition, also provides flexibility for the exploration of different future market designs. The Commission considers that its proposed access model is likely to be an appropriate, no regrets step that is suitable for any post 2025 design of the market, because the access model is premised on the fundamental market design principle of marginal pricing.

The ESB noted in its post-2025 market design issues paper that the COGATI review will determine where on the spectrum of approaches the future market design will lie. Any recommendations the post 2025 project makes will be consistent with the COGATI review and look to build upon the proposals.[28]

C.4 Renewable energy zones

The Commission is continuing to develop its recommendations for renewable energy zones, working closely with the ESB (which has been tasked by the COAG Energy Council to expedite work on short term actions to progress renewable energy zone connections), the Australian Energy Market Operator (AEMO), the Clean Energy Finance Corporation (CEFC) and the Australian Renewable Energy Agency (ARENA).

The ISP would be the mechanism by which the shared transmission network infrastructure related to priority REZs is delivered. The access model would then provide signals to market participants, including generators and storage, to utilise this infrastructure efficiently, in both operational and investment time-scales.

27 http://www.coagenergycouncil.gov.au/publications/consultation-draft-isp-rules

28 Energy Security Board, *Post 2025 Market Design Issues Paper*, September 2019, p. 28.